To: U.S. Department of Energy via e-mail to Economic.Dispatch@hq.doe.gov

From: Western Farmers Electric Cooperative

Regarding: Response to questions related to economic dispatch

Contact: For additional questions or clarification, the DOE may contact James Liao, of Western Farmers Electric Cooperative, at j_liao@wfec.com or at (405) 247-4286.

Mr. David Mohre with the National Rural Electric Cooperative Association forwarded the letter from Mr. David H. Meyer, Acting Deputy Director of the Office of Electricity Delivery and Energy Reliability for the U.S. Department of Energy. That letter dated September 1, 2005, was seeking input from the utility industry regarding economic dispatch. Western Farmers Electric Cooperative (WFEC) is submitting the following in response to that request.

WFEC is an electric generation and transmission cooperative headquartered in Anadarko, Oklahoma. WFEC owns, operates, and maintains approximately 3,600 miles of transmission lines located principally in Oklahoma, and comprises nineteen distribution cooperatives and Altus Air Force Base, serving approximately 250,000 meters in Oklahoma, Texas, Kansas and Arkansas. WFEC's transmission facilities are subject to administration by the Southwest Power Pool, Inc. ("SPP") under SPP's Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission. WFEC also owns natural gas pipelines connected to the intrastate pipeline grid to deliver fuel to its Mooreland and Anadarko generating facilities, as well as fourteen miles of railway facilities (through its wholly-owned subsidiary WFEC Railroad Company) to deliver coal to its Hugo Plant. WFEC presently obtains electric energy for resale to the Members from multiple sources:

Plant	Owner	Nameplate Rating
Anadarko Steam Plant	WFEC	76 MW
Anadarko CC Plant	WFEC	352 MW
Mooreland Plant	WFEC	322 MW
Hugo Plant	WFEC	440 MW
GENCO Plant	GENCO	90 MW
Blue Canyon Wind Power	Blue Canyon	74 MW
SWPA Hydro Peaking	SWPA	279 MW

In addition to the generating plants listed above, WFEC obtains energy from market purchases.

1) What are the procedures now used in your region for economic dispatch?

Response: Currently economic dispatch is performed individually by multiple control areas located in the SPP footprint and even by some load serving entities located within these host control areas. There is no regional economic dispatch at SPP at the present time. The SPP Regional Transmission Organization ("RTO") will perform RTO-wide Security Constrained Economic Dispatch ("SCED") when the Phase-1 Energy Imbalance Market starts, currently scheduled for May 1, 2006. The participation in SCED will be voluntary and price based. Generators interested in SCED will submit offer curves for SPP to determine the optimal way to dispatch the units recognizing transmission constraints. The offer price curves do not have to be equal to actual generation cost.

Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

SPP peak demand was 38,767 MW and total generating capacity was 55,984 MW in 2004. SPP's members cover a 250,000 square mile region over all or part of eight states and serve approximately 4 million customers. This demand is located within the SPP and is sited in various control areas bounded by interchange meters that are not always geographically isolated from other control areas, but electrically each control area maintains a discreet body electrically identifiable from every other control area. The control areas within the SPP range in size from a few hundred MW of demand to thousands of MW of demand and the generation resources within each control area are equally as variable in ownership as well as design and size.

WFEC as a utility performs economic dispatch in real-time operations once every 60 seconds on the Energy Management System (EMS). Prior to real-time operations, WFEC also purchases economy energy from both utility and non-utility generation resources. Economy energy is normally purchased as a multiple of 50 MW either for all the on-peak hours or for all the off-peak hours day-ahead. A variable amount of economy energy may also be purchased on an hourly basis hour-ahead. During the real-time operations, economic dispatch is designed to load all the on-line generators based on "equal incremental cost" criterion via Automatic Generation Control (AGC) on the EMS system. Other utilities, load serving entities, and generators within the SPP perform economic dispatch as it relates to their generating or load serving responsibilities. WFEC's economic dispatch is limited to on line generation and has no ability to change the status of off line resources without human intervention. In this regard economic dispatch is only concerned with loading resources automatically available to produce the lowest cost solution to supply the ever changing demand of the WFEC control area. Economic dispatch alone is not always the least expensive way to serve load. Only through recognition of operating limits can economic dispatch start to be the least cost solution available to reliably serve customer load.

After the SPP Energy Imbalance Market goes live, WFEC plans to offer some of our generation resources to SPP and participate in the RTO-wide security constrained economic dispatch.

2) Is the Act's definition of economic dispatch (see above) appropriate?

Response: Economic dispatch is a minute-to-minute decision and is performed only with **on-line** generating units. The Energy Policy Act of 2005 defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost ….." It is not clear what the "generation facilities" encompass. If the "generation facilities" include all the **off-line** units, it becomes a much more complicated problem and is generally referred to as "unit commitment and economic dispatch." The definition is not adequate in that it does not describe the time interval economic dispatch covers. It is easy for persons not familiar with economic dispatch to assume the time horizon extends over time instead of only covering a snap shot in time. Further, the definition should clearly explain economic dispatch does not extend to off line generation or the removal of on line generation from service.

Over what geographic scale or area should economic dispatch be practiced?

An RTO footprint would be a good geographic area for economic dispatch. This would be true only however if physical delivery over the entire RTO is possible and requires a robust transmission system that may not exist today. Without the ability to supply the entire region included in economic dispatch the solution must use a SCED model that recognizes the identifiable operating limits thereby physically modifying the solution. Producing an economic dispatch solution requires all limiting factors be identified before the solution set can be validated.

Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

Long-term fuel constraints such as take-or-pay contracts, long-term emission constraints such as air permit limitations, annual SO_2 allowances, and short-term to real-time NOx emission constraints, need to be considered in economic dispatch. If economic dispatch extends into longer horizons of time, the recovery of installation cost of generation may need to be included in the price signal for each resource. Without considering these type limitations economic savings achieved during one period of time may be far outweighed by the cost associated with economic penalties associated with non compliance or debt repayment. Transmission losses should also be considered in economic dispatch. Recent experiences in the Midwest Independent System Operator (MISO) market have seen loss charges and uplift charges that negate the economic dispatch savings calculated in the real time horizon. Economic dispatch may be performed based on "pseudo prices" that are adaptively determined to recognize the various real-time, short-term and long-term constraints.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

Response: There is no RTO-wide economic dispatch at SPP at the present time and WFEC is not aware of any procedural differences between utility-owned and non-utility-owned generation in the future RTO Market. Public Utility Commission and self governed rate regulation however is based on cost recovery. Moving from the current economic dispatch by utilities will require rate adequacy for recovery of stranded cost to prevent under collection through demand portions of rates predicated on operating assets that may be idled through a regional economic dispatch. This may or may not occur, but will need to be evaluated on a utility by utility basis and may not be adequately addressed by economic dispatch alone.

Economic dispatch should exclude intermittent resources such as wind generators and any other generating resources that are not dispatchable.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

Response: There is no RTO-wide economic dispatch at SPP currently. The Phase-1 Energy Imbalance Market should lead to more non-utility generation dispatch. However, the Security Constrained Economic Dispatch (SCED) will be done every five minutes and there will be no make-whole payments for start-up cost and no-load running cost. The risk for non-utility generators participating in SCED at SPP is that the cost to start and keep the generators on-line may not be fully recovered if generators are not deployed by SPP continuously. A market with Security Constrained Unit Commitment (SCUC) that accepts three-part offers and guarantees make-whole payments will better enable economic dispatch participation by non-utility generators. The three-part offers include start-up cost, no load running cost, and incremental cost.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

Response: Economic dispatch is only concerned with the dispatch of **energy.** Unit commitment will consider both **capacity** and **energy**. This question seems to make it unclear if the economic dispatch defined in the Energy Policy Act includes unit commitment. Again, the Energy Policy Act of 2005 definition for economic dispatch must address the time horizon intended to be covered by economic dispatch. The questions the DOE posed tend to consider economic dispatch as a more powerful cost saving procedure that includes a time horizon far beyond dispatching on line generation. The DOE should not overstate the capabilities of economic dispatch to include unit commitment and regional capacity planning for generation and transmission. Regional economic dispatch in truth should make only a minimal change to the mix of capacity available for dispatch unless constraints to transfer of power between generators and loads are eliminated.

Economic dispatch will load all the on-line units at equal incremental cost in the absence of transmission congestion regardless of the ownership and location of the units. Since the transmission system has been built mostly to allow utility generation to serve utility load, the transmission grid might not be operated as designed due to greater dispatch of non-utility generation. As a result, the grid may be more vulnerable to disturbances. If retail customers are allowed to shop for capacity and energy region-wide, retail rates will be more equalized within the same region. The energy costs in high-cost producing states will come down while the energy costs in low-cost producing states will go up. This economic redispatch will materially affect the ability of generation and transmission owners to recover the cost associated with reliably planning for the **capacity** needs of firm load customers over the long run. Some entities will be winners and some will be losers and thus the socialization of this cost will become an issue to be addressed by regulatory bodies with authority over rates.

States with more efficient non-utility generators, such as Oklahoma, may end up with more emissions if most of these generators get committed and dispatched to serve load in other states with less efficient utility generation of older vintage.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Response: Since economic dispatch, as defined in the Energy Policy Act of 2005, recognizes the operating limits of transmission facilities, it should not significantly reduce grid reliability in the static state. The DOE should acknowledge stability operating limits are very real impediments to economic dispatch that changes the complexity of economic dispatch in an absolutely huge way. However, greater dispatch and use of non-utility generation may pose system transient stability concerns due to the following two reasons:

1. It has been a challenge to most Independent System Operators ("ISO's") and RTO's to consider transient stability constraints in security constrained economic dispatch. The larger the dispatch region, the more important transient stability constraints will be. Without adequately considering transient stability constraints, economic dispatch may lead to power system operations in transiently unstable regions.

2. Non-utility generators often do not share the same responsibility of voltage control as do utility generators in terms of reactive power (Var) generation. In fact recent generation and associated equipment designed for merchant operations may not have the same capabilities to provide voltage control as incumbent utility generation and would need to be evaluated. Greater dispatch and use of non-utility generation may reduce the availability of dynamic Var control and reduce grid reliability. Optimal Power Flow (OPF) with transient stability constraints (OTS) may be used to insure both real power (MW) and reactive power (Var) are considered in security constrained economic dispatch.

A modified approach of economic dispatch is to include loads in economic dispatch via real-time pricing since load reduction works just like generation increase in real-time. The “Smart Metering” requirement in Section 1252 of the Energy Policy Act of 2005 should help in bringing loads to economic dispatch via an effective demand response program. However, it will be quite costly for utilities to provide the communication infrastructure and replace all the existing meters with time-based meters.